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MODELING APPROACHES FOR WELLBORE BOUNDARY CONDITIONS FOR SIMULATION OF CO_2 GEOLOGIC SEQUESTRATION IN SALINE AQUIFERS

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ABSTRACT

Numerical simulations have been widely used for CO_2 storage site characterization. The performance of CO_2 injection into saline aquifers can be evaluated by use of site-scale numerical models. Within such models, the treatment of well boundary conditions is one of the most challenging tasks. The difficulty arises because the maximum changes in primary variables and occurrences of maximum mass/heat fluxes occur at wells or in nearby gridblocks. Consequently, these gridblocks may have relatively bad computational convergence. Most simulations use a sink/source term to represent the injection, and directly apply the injection flux to well gridblocks. In a real CO_2 sequestration project, a long well screen may be needed to guarantee sufficient injectivity, regardless of well orientation (vertical, deviated, or horizontal). In modeling, the injected flux allocation along the well screen must typically be determined.

In this paper, three modeling approaches for simulation of long-screen injection wells are proposed. These approaches intend to accurately distribute injection fluxes by a potential or mobility allocation scheme for a multilayered well or a horizontal well. The three approaches include "fixed screen top pressure," "distributed pressure," and "virtual block" methods. Here, implementations of these approaches are discussed, and the advantages and disadvantages of the different approaches are investigated.

INTRODUCTION

CO_2 is the most important greenhouse gas because of its large global emission rate and longevity in the atmosphere. Finding suitable locations for permanently sequestering captured CO_2 is crucially important for reducing net CO_2 emissions. Deep saline formations are thought to be good candidates for CO_2 sequestration, due to their large potential capacity. Numerical simulations play an important role in CO_2 storage site characterization. The performance of CO_2 injection into saline aquifers can be evaluated through numerical modeling studies. Treatment of well boundary conditions is one of the most challenging tasks for numerical simulations because the maximum changes in primary variables and occurrence of maximum mass/heat fluxes occur at wells or in nearby gridblocks. Most site-scale simulations reported in the literature (Yamamoto, et al., 2009; Zhou, et al., 2010) use a sink/source term to represent injection and directly apply the injection flux to well gridblocks. However, actual field injections often use multilayered wells, which must distribute injection to multiple layers. In many cases, efficient and rigorous treatment of well conditions is critical for successfully modeling large-scale CO_2 storage. Fully coupled wellbore-reservoir simulation, with an accurate accounting of well conditions, could be a sensible approach for handling flow from wells to aquifers. Simulation of the fast non-Darcy flow in the wellbore, coupled with slow multiphase Darcy flow in the reservoir, limits convergence rates (Pan, et al.

2011) which may make this coupled approach unsuitable for site-scale reservoir simulations.

Strictly speaking, a well boundary condition in multiphase modeling is a “constraint condition” rather than a rigorous “boundary condition” as used in the mathematical sense for solving partial differential equations [Wu et al., 1996]. Yet accurately allocating (as part of a simulation) injected CO_2 to multi-layer system is a challenging task. The conventional method of well treatment in groundwater, geothermal, and oil reservoir simulations for multiphase flow involves (for a multi-layered well) using a sink/source term approach and distributing flow rates by a potential or mobility allocation scheme [Aziz and Settari, 1979]. This approach is good for most well boundary simulations when modeling CO_2 sequestration: it can estimate correct total fluid injection/production rates as long as the maximum and minimum pressure constraints are not violated. Backflow, however, may occur in multilayered wells within a thick, heterogeneous formation or a long horizontal well. The mobility allocation method, however, distributes grid-layer fluxes along a well based on a mobility ratio and without considering the effects of pressure or potential gradients. This method is easy to implement, but may result in physically incorrect solutions and poor numerical performance [Wu et al., 1996]. In response to this problem, Wu (2000) proposed a “virtual node” approach for treatment of well boundary conditions which allows for backflow.

In this paper, we propose three approaches for injection-fluid allocation along long-screened wells. The three approaches are “fixed screen top pressure,” “distributed pressure,” and “virtual block.” The “fixed screen top pressure” approach applies a constant pressure or constant injection rate at the top-well-screen gridblock. Flux migrates down to the well bottom or to the storage aquifers of the top-well-screen gridblock. Allocation of CO_2 fluxes to different layers proceeds according to pressure differences and flux mobilities in the corresponding formations. The “distributed pressure” approach uses a constant pressure along the well screen for CO_2 injection. Pressure gradient along the well screen is determined from gravity equilibration. The “virtual block” approach simulates a well bore either as a single gridblock or several computational gridblocks screened and connected to many neighboring gridblocks within a multilayered well. In this approach, the wellbore can be vertical, inclined, or horizontal, and the well borehole gridblock is treated in the same way as any other non-well gridblocks for flow calculations. This approach can handle the backflow problem that might occur in a multilayered well within a heterogeneous formation. The proposed approaches have been applied to site-scale CO_2 injection simulations as part of China’s first full-process CO_2 sequestration project, the Shenhua Ordos CO_2 sequestration demonstration project.

METHODOLOGY

It is generally understood that a well is screened in multiple layers by means of regions of perforations in the well casing. Injected flux moves downward through the wellbore and then enters into aquifers through these perforated regions. Figure 1 provides a schematic illustration of flow in the wellbore. Such flow is usually not expected to obey Darcy’s law. The Equivalent Darcy’s Media (EDM) approach has been widely used to simulate wellbore flow as a convenient approximation, especially if the wellbore flow simulation is coupled to reservoir simulation (Birkholzer et al., 2011). Equivalent parameters must be determined for the EDM approach: While researchers often choose a high permeability for the wellbore, it is hard to know how large it should be for any given problem. Hu et al. (2012) demonstrated that for their problem, an equivalent permeability of 3.16×10^{-6} m^2 can produce a good match between a fully coupled wellbore-reservoir simulation and the EDM approach. We use the EDM approach with high permeability for the wellbore boundary conditions.

The "fixed screen top pressure" approach treats the screen's top gridblock (see Figure 1) as a first-type boundary. This approach can be used for constant pressure or constant rate injection. Pressure at that gridblock is determined by the injection pressure at the top of the well using a wellbore simulator. We use T2WELL (Pan et al. 2011) for the calculation, which simulates flow moving downward within the wellbore. Very high permeability is selected for the EDM guaranteeing vertical flow in the borehole. Total injection rate equals the downward flow rate in the wellbore from the screen-top gridblock, which can be determined by the reservoir simulator at each time step. An alternative approach for constant-rate injection is to apply a constant injection rate at the screen-top gridblock. The injected CO_2 moves downward through the high-permeability EDM and migrates into the storage aquifers. Distribution of CO_2 among storage layers is determined by the pressure gradient and mobility of the layers.

The "distributed pressure" approach is also used for simulating constant-pressure injection. In this approach, the pressures along the well screen are known. Pressures at different elevations are determined through wellbore simulation or estimated using fluid density under the reservoir temperature and pressure conditions. CO_2 migrates into the formation layers from the well gridblocks with a fixed pressure. Total CO_2 injection rate is the sum of the flow rate from well gridblocks into storage aquifers.

The "virtual block" method handles a wellbore as a single gridblock or as several gridblocks (Wu, 2000). Figure 1 illustrates a virtual gridblock representation of a well and its association with formation layers and model grids in a multilayered, vertical wellbore. In this approach, the mass balance and discrete equations are still applicable to well gridblocks. However, the coefficients for flow terms are evaluated differently. In this case, an injectivity index is used for wellbore–formation flow, while wellbore mobility and transmissivity are used for wellbore–wellbore flow.

In TOUGH2 simulation, mobility (λ_β) and transmissivity (γ_{ij}) of flow terms are defined as (Pruess, et al. 1999),

$$\lambda_\beta = k_{r\beta} / \mu_\beta \qquad (1)$$

$$\gamma_{ij} = \frac{A_{ij} k_{ij}}{d_i + d_j} \qquad (2)$$

where $k_{r\beta}$ is the relative permeability of phase β, μ_β is the fluid viscosity in phase β, A_{ij} is the common interface area between connected gridblocks i and j, d_i is the distance from the center of gridblock i to the interface between gridblocks I, and j, k_{ij} is the permeability for the connection between gridblocks i and j, which can be determined using different weighting schemes from the permeability of gridblocks i and j.

Flow between wellbore gridblocks is simulated using the EDM approach. Mobility and transmissivity of the EDM are used for the calculations. The injectivity index needed for wellbore–formation flow calculation can be calculated using many different methods (e.g., Thomas, 1982; Fung et al., 1991). The well index formulation by Thomas (1982) is:

$$II_{ij} = \frac{2\pi k \Delta z_j}{\ln(\frac{r_e}{r_w}) + s - 1/2} \qquad (3)$$

where Δz_j is the thickness of layer j, r_e and r_w are an equivalent radius of gridblock j and the well bore radius, respectively, and s is the skin factor. Through selecting appropriate d_i and A_{ij} for the connection of well gridblock to the neighboring formation gridblocks, we can determine a transmissivity equivalent to the effect of the well injectivity index. By this approach, the well gridblocks can be treated in the same way as regular formation gridblocks, except using equivalent parameters of d_i and A_{ij}.

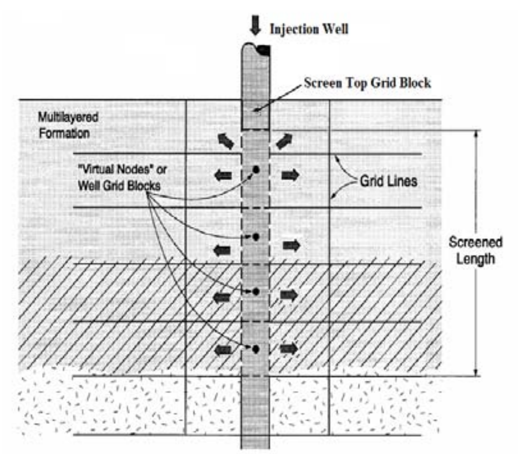

Figure 1. Schematic illustration of wellbore boundary conditions (Modified from Wu, 2000)

EXAMPLES

CO_2 storage in saline aquifers was simulated to observe the CO_2 flow and injectivity by using different wellbore boundary conditons based on the Shehua CCS Project, China's first fully integrated CCS demonstration project. The proposed three approaches, "fixed screen top pressure," "distributed pressure," and "virtual block," are applied in describing the wellbore boundary conditions. The "fixed screen top pressure" approach applies a constant pressure or injectivity at the top gridblock of the wellbore screen for CO_2 injection. Two models—modeling constant injectivity according to actual injection, and modeling constant pressure injection at a pressure of 1.3 times the initial formation pressure—are present for demonstration of this approach. The "distributed pressure" approach simulates constant pressure along the wellbore based on gravity equilibration. A constant pressure of 1.3 times initial equilibrium presssure is applied to the well screen for CO_2 injection. The "virtual block" method uses a single gridblock connected to all wellbore gridblocks for the simulation.

The Shenhua CCS project calls for injecting 100,000 Ton/Yr CO_2 into low-permeability sandy aquifers, within the Ordos Basin in Inner Mongolia. The injection well was drilled to a depth of around 2500 m. Storage aquifers are distributed between the depths of 1690–2400 m, which are interlayered by clay formations. Injection screens are opened to multiple aquifers, represented by 21 model layers. The aquifers have a thickness of several meters with permeability of several millidarcy. Storage layers are numbered as INJ01 to INJ21 from top to bottm. Hydraulic fracturing was conducted at INJ05, INJ06 and INJ15-INJ21 for improving injectivity. A three-dimensional numerical model was developed for simulating CO_2 injection in the site using TOUGH2-MP (Zhang et al., 2008).

Numerical experiments indicate that a model domain of 10 km×10 km is sufficient for treating the four sides as first-type boundaries. Vertically, the model covers the depth from 1680 to 2400 m, including all storage aquifers and clay interlayers (Figure 2). The injection well is located at the center of the model domain. The 10 km×10 km model domain was discretized into 7481 gridblocks for each model layer, with five levels of refinement around the injection well (see Figure 3). In the vertical direction, the domain was discretized into 59 model layers. At the center of the mesh, a special area with 90 m length and 1 m width along 5 degrees east to north represents hydraulic fracturing zones (Figure 3), and a permeability of 100 mD is assigned to these fracturing zones. Four sides of the domain are treated as first-type boundaries, whereas the top and bottom of the model are non-flow boundaries. The well boundary condition is treated by the three different approaches, as discussed above. Intial contitions of the model are determined based on measured geothermal gradient, gravity equilibrium pressure distribution, and a constant 3% salt mass fraction. Model parameters were provided by core measurements and tests.

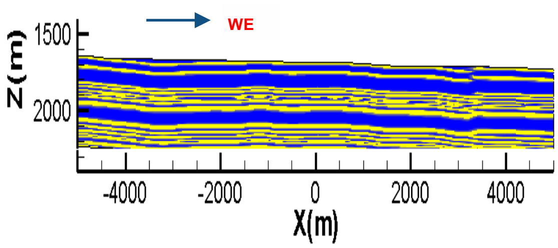

Figure 2. Eest-West cross-section the the model domain (yellow: storage formations, blue: clay layers)

Figure 4 shows the simulated percentage of flux distribution among several key storage layers for the cases with specified injection rate at the top well-screen gridblock (TOP_Q), constant pressure at the top well-screen gridblock (TOP_P_1.3P0), distributed pressure (Dis_P_1.3P0), and virtual block approaches, respectively. All cases show that a high percentage of CO_2 flows into the hydraulic fracturing zone (FRACT) at the beginning. The fluxes reach a peak amount in a couple of months and then drop dramatically afterwards. All these cases show higher percentage fluxes flowing into storage layers INJ01 and INJ06. Both layers have relatively high permeability. Hydraulic fracturing was conducted at INJ06 which may help to improve the storage capacity at the layer. This indicates that the flux migrating into each layer is governed by phase mobility in the formation, no matter how the injection occurred. Among the four cases, TOP_P_1.3P0 and Virtual_block have higher percentages than the TOP_Q and Dis_P_1.3P0 cases for the two layers. INJ01 and INJ06 layers receive similar percentage fluxes (~11%–13%). Every other layer receives less than 10% of the total flux. In distributed pressure schemes, flux discrepency among different layers is relatively small. Most layers receive lower than 10% fluxes. The two cases for “fixed screen top pressure” (TOP_Q and TOP_P_1.3P0) have similar pressure gradient from top to bottom layers. This is comfirmed by the fact that the sequence of flux percentage for the storage layers is almost identical.

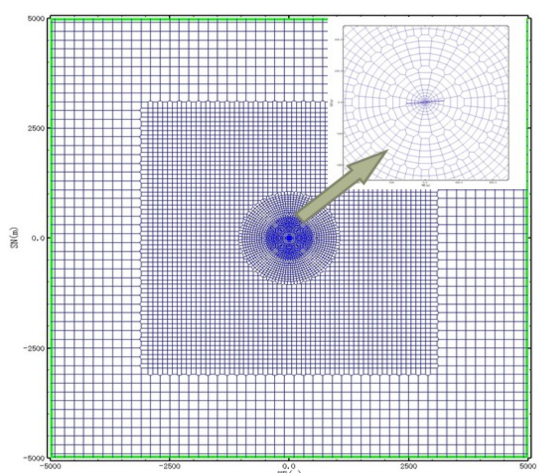

Figure 3. Plane view of the three-dimensional mesh

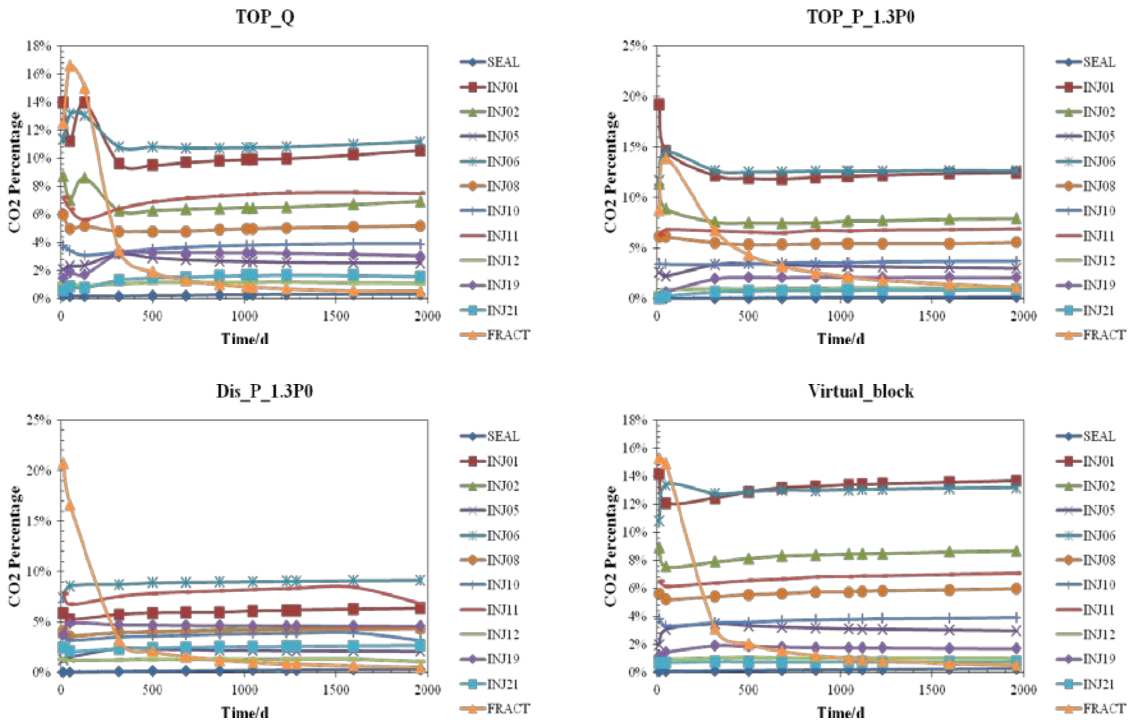

Figure 4. Simulated flux distribution at different layers using (a) fixed rate at the top screen gridblocks , (b) fixed pressure at the top screen gridblocks, (c) the “distributed pressure” approach, (d) the “virtual block” approach

Figure 5 shows the supercritical gas-saturation distribution at the layer INJ06 for the TOP_Q approach, after a 10-day injection. Other approaches produce similar gas saturation distributions. It is clear that the gas distribution is mainly controlled by the hydraulic fracturing zone; gas flow is faster along the fracturing region than in the formation. That may indicate hydraulic fracturing can effectively improve CO_2 injectivity.

The vertical profile of CO_2 gas saturation after a 5.36-year injection for different wellbore boundary condition approaches are shown in Figure 6. The TOP_Q, TOP_P_1.3P0 and Virtual_block cases demonstrate more significant injection at the top layers than the Dis_P_1.3P0 case. This is because the three approaches may have relatively larger pressure gradients between the wellbore and formations at the top layers. It is also the reason why the CO_2 plumes in INJ01 and INJ02 are quite different between the Virtual block scheme and other schemes. Clearly, the pressure gradient between wellbore and storage formations is still one of the key factors controlling flux distribution in the storage layers.

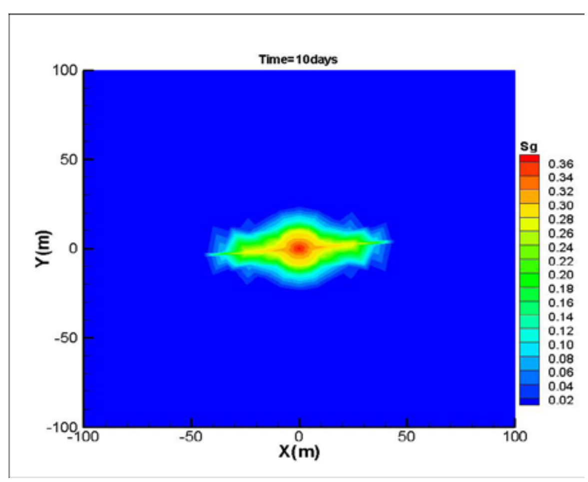

Figure 5. Plane view of CO_2 gas saturation distribution in layer INJ06

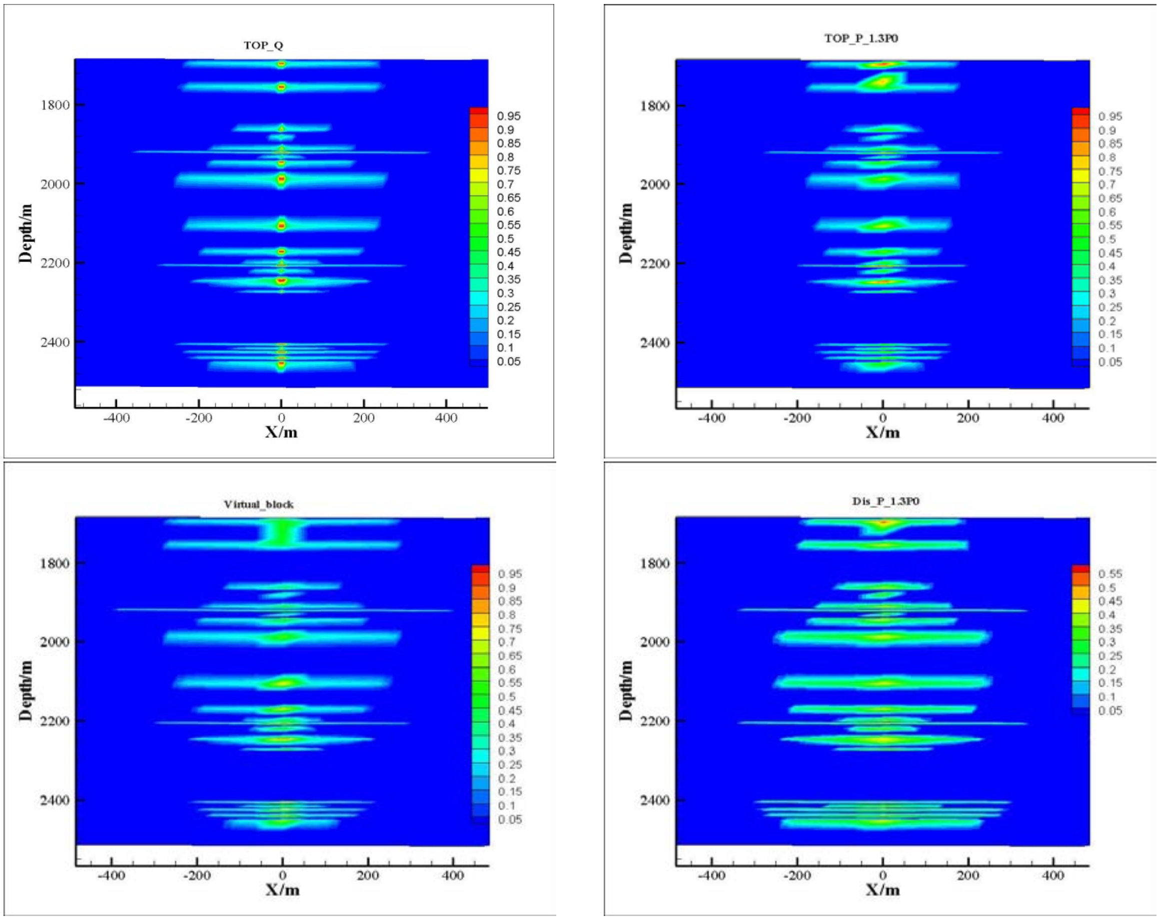

Figure 6. The vertical profile of gas saturation using different wellbore boundary condition approaches: (a) fixed rate at the top screen gridblocks, (b) fixed pressure at the top screen gridblocks, (c) the “distributed pressure” approach, (d) the “virtual block” approach

Simulation results indicate that the different wellbore-boundary-condition approaches may produce quite different results. In most cases, CO_2 injection with a specified rate or pressure at the well head is used. This type of operation can be simulated using the “fixed screen top pressure” approach. If pressure along the wellbore screen does not show a significant gradient, the “virtual block” approach may be selected for the simulation. The “distributed pressure” approach may be used for simulating wells with detailed information about injection pressure along the wellbore screen.

CONCLUSIONS

We propose three approaches—“fixed screen top pressure,” “distributed pressure,” and “virtual block,”—for treatment of wellbore boundary conditions. These three approaches provide different schemes for injection-fluid allocation along long-screened wells. The “fixed screen top pressure” approach applies a constant pressure or constant injection rate at the top gridblock of the well screen. This approach may be suitable for simulating CO_2 injection with a specified rate or pressure. The “distributed pressure” approach uses a constant pressure along the well screen for CO_2 injection. This approach can be used in simulations with detailed information on injection pressure along the wellbore screen. The “virtual block” approach simulates a wellbore (in a multilayered well) either as a single gridblock or several gridblocks screened and connected to many neighboring gridblocks. The "virtual block" approach is suitable for simulation of wells without a significant pressure gradient along the wellbore screen.

The proposed approaches were applied to the site-scale CO_2 injection simulations within China's first fully integrated CO_2 sequestration demonstration project. They can effectively simulate CO_2 injection processes and obtain reasonable CO_2 flux distribution among different layers. Note that simulation results show different approaches may produce quite different results. In real injection simulations, an approach best representing field operations must be selected.

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